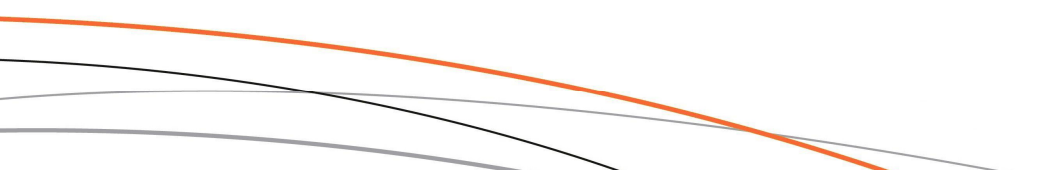


Anderson Energy Announces 2016 Second Quarter Results

Calgary, Alberta, August 11, 2016 - Anderson Energy Inc. ("Anderson" or the "Company") (TSX:AND) announces its operating and financial results for the second quarter ended June 30, 2016. The Company will be filing its unaudited condensed interim financial statements and management's discussion and analysis ("MD&A") for the three and six months ended June 30, 2016 on SEDAR today. Copies can be found under the Company's profile on www.sedar.com and on the Company's website at www.andersonenergy.ca.

HIGHLIGHTS

- On May 10, 2016, Anderson exchanged the principal amount (\$46 million) of the 7.25% Series B convertible unsecured subordinated debentures (the "Series B Debentures") and the interest that would have otherwise been payable on June 30, 2016 (\$1.667 million) for common shares at the same exchange price used in the first quarter of 2016 to repay the principal amount (\$50 million) and the final interest payment (\$1.875 million) on the 7.50% Series A convertible unsecured subordinated debentures that matured on January 31, 2016 (the "Series A Debentures").
 - Effective June 15, 2016, Anderson consolidated its outstanding common shares on the basis of one (1) post-consolidation common share for every one thousand (1,000) pre-consolidation common shares. The share consolidation was approved at an annual meeting of shareholders held on June 14, 2016. The post-consolidation common shares began trading on the Toronto Stock Exchange (the "TSX") under the symbol "AND" on June 20, 2016. The pre-consolidation common shares were previously traded under the symbol "AXL".
 - As of June 30, 2016, the Company had no debt, positive working capital of \$5.1 million and an \$18 million undrawn bank facility.
 - Production in the second quarter of 2016 was 1,659 BOED (42% oil, condensate and NGL), down 27% from the second quarter of 2015. The 27% decrease was due to shallow gas property dispositions (9%), decline off initial flush rates from the prior year's drilling program (15%), and a decline in base production (3%). There has been no new production brought on since March 2015. Cardium production represented 1,387 BOED (47% oil, condensate and NGL) of second quarter production.
 - Funds from (used in) operations for the three months ended June 30, 2016 were \$(0.1) million compared to \$1.5 million in the second quarter of 2015. The convertible debentures have been settled in 2016 and there was no cash interest paid on the debentures in 2016. Funds from (used in) operations before interest on convertible debentures were \$0.3 million for the three months ended June 30, 2016 and \$(0.1) million for the first quarter of 2016.
 - The operating netback in the second quarter of 2016 was \$8.27 per BOE compared to \$21.54 per BOE in the second quarter of 2015. The operating netback from Cardium properties in the second quarter of 2016 was \$16.33 per BOE.
 - With the weak commodity prices, the Company made additional changes to its administrative cost structure effective March 1, 2016 which are expected to reduce 2016 gross G&A expenses by \$1.0
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million compared to 2015. The Company also implemented several changes in the field during 2015 and 2016, which are expected to result in operating costs of approximately \$11.00 per BOE in 2016.

- A new horizontal oil development project has been added to the Company's portfolio in central Alberta in the Duvernay Carbonates. Anderson has assembled over 12 sections of 100% working interest land in this project area, which is prospective for light oil horizontal drilling at medium depth.

FINANCIAL AND OPERATING HIGHLIGHTS

(thousands of dollars, unless otherwise stated)	Three months ended June 30			Six months ended June 30		
	2016	2015	% Change	2016	2015	% Change
Oil and gas sales ⁽¹⁾	\$ 3,353	\$ 7,092	(53%)	\$ 6,807	\$ 14,081	(52%)
Revenue, net of royalties ⁽¹⁾	\$ 3,117	\$ 6,629	(53%)	\$ 6,281	\$ 12,882	(51%)
Funds from (used in) operations	\$ (99)	\$ 1,456	(107%)	\$ (1,298)	\$ 1,731	(175%)
Funds from (used in) operations per share ⁽²⁾ - basic and diluted	\$ (0.01)	\$ 8.44	(100%)	\$ (0.13)	\$ 10.03	(101%)
Adjusted earnings (loss) before taxes ⁽³⁾	\$ (4,325)	\$ (4,037)	(7%)	\$ (8,707)	\$ 20,263	(143%)
Adjusted earnings (loss) before taxes per share ⁽²⁾⁽³⁾ - basic and diluted	\$ (0.31)	\$ (23.40)	(99%)	\$ (0.85)	\$ 117.43	(101%)
Earnings (loss)	\$ (4,798)	\$ (4,053)	(18%)	\$ (9,180)	\$ 19,870	(146%)
Earnings (loss) per share ⁽²⁾ Basic and diluted	\$ (0.34)	\$ (23.49)	(99%)	\$ (0.90)	\$ 115.16	(101%)
Capital expenditures (net of proceeds on dispositions)	\$ 643	\$ (314)	305%	\$ 2,135	\$ (28,472)	107%
Adjusted working capital				\$ 5,089	\$ 4,410	15%
Convertible debentures				\$ -	\$ 92,623	(100%)
Shareholders' equity (deficit)				\$ 44,293	\$ (7,677)	677%
Average shares outstanding ⁽²⁾ (thousands):						
Basic and diluted	14,159.7	172.6		10,240.1	172.6	
Ending shares outstanding ⁽²⁾ (thousands)				17,771.5	172.6	
Average daily sales:						
Oil and condensate (bpd)	544	897	(39%)	596	993	(40%)
NGL (bpd)	159	146	9%	153	154	(1%)
Natural gas (Mcf)	5,737	7,306	(21%)	6,138	8,007	(23%)
Barrels of oil equivalent (BOE) ⁽⁴⁾	1,659	2,260	(27%)	1,772	2,481	(29%)
Average prices:						
Oil and condensate (\$/bbl)	\$ 52.01	\$ 65.00	(20%)	\$ 45.01	\$ 55.67	(19%)
NGL (\$/bbl)	\$ 9.00	\$ 8.99	-	\$ 7.48	\$ 11.45	(35%)
Natural gas (\$/Mcf)	\$ 1.24	\$ 2.51	(51%)	\$ 1.54	\$ 2.59	(41%)
Barrels of oil equivalent (\$/BOE) ⁽⁴⁾	\$ 22.20	\$ 34.48	(36%)	\$ 21.11	\$ 31.36	(33%)
Royalties (\$/BOE)	\$ 1.57	\$ 2.25	(30%)	\$ 1.63	\$ 2.67	(39%)
Operating costs (\$/BOE)	\$ 11.95	\$ 10.38	15%	\$ 11.32	\$ 10.38	9%
Transportation costs (\$/BOE)	\$ 0.41	\$ 0.31	32%	\$ 0.34	\$ 0.32	6%
Operating netback (\$/BOE) ⁽³⁾	\$ 8.27	\$ 21.54	(62%)	\$ 7.82	\$ 17.99	(57%)
Wells drilled (gross)	-	-	-	-	2	(100%)

⁽¹⁾ Includes royalty and other income classified with oil and gas sales.

⁽²⁾ Prior period shares outstanding and amounts per share have been restated to reflect the consolidation of common shares on the basis of one (1) post-consolidation common share for every one thousand (1,000) pre-consolidation common shares.

⁽³⁾ Adjusted earnings (loss) before taxes, adjusted earnings (loss) before taxes per share and operating netback per BOE are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" in the MD&A for a more complete description of these non-GAAP terms, reconciliations to the closest related GAAP measures, and the purposes for which management uses the non-GAAP measures. These non-GAAP measures may not be comparable with the calculation of similar measures for other entities.

⁽⁴⁾ Barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

OPERATING ENVIRONMENT

Oil and natural gas prices continue to be low in 2016. The average WTI oil price per bbl was approximately \$45.60 US in the second quarter of 2016, \$33.52 US in the first quarter of 2016 and \$48.76 US for the full year of 2015. The lowest average monthly oil price seen to date in 2016 was \$30.62 US per bbl, realized in February 2016. The price had improved to \$48.85 US for June 2016 before softening to approximately \$42.77 US to date in August 2016. Recent average NYMEX futures pricing for WTI for the fourth quarter of 2016 is approximately \$45.11 US per bbl (\$59.22 Canadian per bbl). The US/Canadian dollar exchange rate moved beneficially from an average of approximately \$0.78 in 2015 to \$0.73 in the first quarter of 2016, before returning to \$0.78 in the second quarter of 2016.

Natural gas prices have also decreased since the fourth quarter of 2015. AECO pricing in April 2016 of \$1.04 per GJ was the lowest it has been in many years. Pricing improved somewhat in later months due to warmer weather resulting in an average AECO price of \$1.33 per GJ in the second quarter of 2016, and \$2.26 per GJ in July 2016. US and Canadian natural gas storage levels and weather will continue to impact prices until the onset of next winter.

In response to the decline in oil prices, the Company stopped its drilling program on January 28, 2015. The Company has since focused its efforts on reducing operating, administrative and capital costs, in both the office and in the field in order to be positioned to resume drilling when commodity prices improve.

OPERATING INITIATIVES

In 2015 and to date in 2016, significant progress has been made in focusing the Company's asset base into the core Cardium operating areas and divesting or shutting in production outside of these focus areas. 199 wellbores were sold and 48 wellbores were abandoned in 2015 resulting in a 37% reduction in the gross active well count (31% reduction in net active well count). In addition, reclamation certificate applications were submitted to the AER for 28 gross (23.7 net) abandoned wells in 2015 and to date, 17 gross (16.3 net) reclamation certificates have been received.

These initiatives have continued into 2016 with 63 gross (48.4 net) well abandonments planned, of which 26 gross (17.3 net) wells have already been abandoned to date in 2016. With this work underway, the Company is actively reducing its long-term decommissioning obligations. The Company is projecting the non-producing well count at year-end 2016 will be further reduced by 25% on a gross basis and 27% on a net basis as a result of the planned 2016 well abandonment program. As of August 1, 2016, the Company's Liability Management Rating (LMR) as determined by the Alberta Energy Regulator (AER) is 2.25, which allows the Company greater operating flexibility. The AER determines the "deemed asset values" and "deemed liability values" of wells and facilities that are operated by any entity (the "Operator"). The LMR is the ratio of "deemed asset values" over "deemed liability values" as determined by the AER. A ratio of less than 1.0 may require an Operator to post a security deposit with the AER, and a ratio of less than 2.0 might restrict an Operator's ability to buy or sell assets under certain regulations proposed by the AER.

Anderson has successfully completed the transition away from its shallow gas legacy, and in the second quarter of 2016, the Company had only 39 gross (27.2 net) producing shallow gas wells which contributed approximately 690 Mcfd, or 12% of the Company's second quarter of 2016 gas production.

Corporate production is now derived primarily from the Cardium formation in the greater Willesden Green operating area, which represents 84% of the production in the second quarter of 2016. Of the remainder, 10% is from various deeper producing formations in the general Sylvan Lake area.

The rebalancing of the asset portfolio has allowed the Company to more effectively focus its resources on the core operating areas resulting in significant reductions in operating expenses, reduced staff count,

and the implementation of a wellbore and facilities decommissioning program that takes advantage of the current low-cost structure from service providers.

2016 PRODUCTION AND CAPITAL PROGRAM

The Company estimates production will be approximately 1,550 to 1,600 BOED (42% oil, condensate and NGL) for the third quarter of 2016 and approximately 1,600 to 1,650 BOED (42% oil, condensate and NGL) for the full year of 2016, assuming no drilling is undertaken in 2016. Production in the second quarter of 2016 was 1,659 BOED (42% oil, condensate and NGL), slightly higher than the second quarter estimate of 1,550 to 1,600 BOED (42% oil, condensate and NGL). The Company's 2016 capital budget of \$3 million is restricted to maintenance capital, capitalized G&A and land acquisitions (net of dispositions). The price trigger to consider starting up a new drilling program is estimated to be approximately \$50 WTI US per bbl. Where possible, Anderson tries to achieve a 12-month or less payout on new drilling projects and the combination of capital costs, operating costs, fiscal regime and commodity prices are the variables that need to be determined prior to undertaking a capital program. As well, due to wet ground conditions in the Willesden Green area in June and July, the earliest the Company could initiate a drilling program would be the fourth quarter of 2016.

LIGHT OIL HORIZONTAL POTENTIAL DRILLING OPPORTUNITIES

The Company's undeveloped light oil horizontal potential drilling opportunities at August 11, 2016, are outlined below:

<i>Prospect Area (number of potential drilling opportunities)</i>	<i>Gross</i>	<i>Net*</i>
Willesden Green Cadium	71	53.2
West Pembina/Buck Lake Cadium	18	7.5
Willesden Green Glauconite	6	6.0
Total Light Oil Horizontal Potential Drilling Opportunities	95	66.7

** Net is net revenue interest.*

GLJ Petroleum Consultants, the Company's independent reserves evaluator, booked undeveloped reserves to 17.3 of these net potential drilling opportunities at December 31, 2015.

The Duvernay Carbonate light oil horizontal project lands acquired in the first quarter of 2016 could yield an incremental four potential horizontal drilling opportunities per section. The Company acquired over 12 sections of 100% working interest lands.

COMMODITY PRICES

A comparison of Anderson's average oil and condensate price to various market prices is presented below. The difference between Anderson's realized price and WTI Canadian is due to the price differential between Cushing, Oklahoma and Edmonton, Alberta, product transportation costs from the field to Edmonton, and adjustments for product quality. There were no financial derivatives or fixed-price contracts in 2016 or 2015.

CRUDE OIL AND CONDENSATE PRICES

	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2016</i>	<i>2015</i>	<i>2016</i>	<i>2015</i>
WTI – \$US	\$ 45.60	\$ 57.96	\$ 39.56	\$ 53.29
WTI – \$Cdn	\$ 58.78	\$ 71.24	\$ 52.37	\$ 65.79
Differential from Cushing to Edmonton – \$US per bbl	\$ 3.10	\$ 2.86	\$ 3.39	\$ 4.81
Edmonton Par – \$Cdn per bbl	\$ 54.78	\$ 67.74	\$ 47.84	\$ 59.76
Anderson average oil price per bbl	\$ 52.87	\$ 65.85	\$ 45.39	\$ 55.98
Anderson average oil and condensate price per bbl*	\$ 52.01	\$ 65.00	\$ 45.01	\$ 55.67

*Condensate includes field condensate and plant condensate.

Monthly WTI Canadian oil prices were \$58.46 per bbl in July and approximately \$56.25 per bbl in August 2016 month to date. Differentials from Cushing, Oklahoma to Edmonton, Alberta were approximately \$1.63 US per bbl in July and \$3.53 US per bbl in August 2016.

Going forward, light oil prices are expected to remain weak in the short term. Over the long term, prices will continue to be volatile and will be influenced by the balance between supply and demand, and by geopolitical events. Differentials between Cushing, Oklahoma and Edmonton, Alberta and the US/Canadian dollar exchange rate will also remain volatile.

A comparison of Anderson's average plant gate natural gas price to various market prices is presented below. The difference between the AECO price and Anderson's plant gate price is due to transportation costs and the heat content of the gas. There were no financial derivative or fixed-price contracts during 2016 or 2015.

The average heat content of the Company's natural gas has increased from 1,098 Btu/scf in the second quarter of 2015 to 1,124 Btu/scf in the second quarter of 2016 due to the new Cardium gas having higher heat content than the Company's legacy shallow gas production. Natural gas is sold on the basis of heat content; therefore, higher heat content gas will yield higher prices per unit of measured volume.

NATURAL GAS PRICES

	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2016</i>	<i>2015</i>	<i>2016</i>	<i>2015</i>
NYMEX \$US per MMBtu	\$ 2.23	\$ 2.74	\$ 2.11	\$ 2.78
AECO \$CAD per GJ	\$ 1.33	\$ 2.52	\$ 1.53	\$ 2.56
AECO \$CAD per MMBtu	\$ 1.40	\$ 2.66	\$ 1.62	\$ 2.70
Anderson average plant gate price per Mcf	\$ 1.24	\$ 2.51	\$ 1.54	\$ 2.59

AECO natural gas prices were \$2.26 per GJ (\$2.38 per MMBtu) in July and approximately \$2.22 per GJ (\$2.34 per MMBtu) month to date in August 2016.

Natural gas prices are influenced by weather and other events and are tempered by the increasing supply of new shale gas. Until meaningful exports of natural gas commence from North America through liquefied natural gas projects, the Company believes that natural gas prices will be range-bound by weather and other events. Warmer weather has contributed to the increase in prices in recent months and the onset and severity of the North American winter will dictate the prices of natural gas next winter.

FINANCIAL RESULTS

Oil and gas sales for the three months ended June 30, 2016 were \$3.4 million compared to \$3.5 million and \$7.1 million in the first quarter of 2016 and second quarter of 2015 respectively. Increases in commodity prices increased oil and gas sales in the second quarter of 2016 by approximately \$0.4 million from the first quarter of 2016, offset by a decrease of approximately \$0.5 million due to lower production volumes.

Oil and gas sales averaged \$22.20 per BOE in the second quarter of 2016 compared to \$20.15 per BOE in the first quarter of 2016 and \$34.48 per BOE in the second quarter of 2015. During the second quarter of 2016, liquids revenue (i.e. oil, condensate and NGL) represented 81% of total oil and gas sales. The Company's operating netback was \$8.27 per BOE in the second quarter of 2016 compared to \$7.40 per BOE in the first quarter of 2016 and \$21.54 per BOE in the second quarter of 2015. Anderson's operating netback for Cardium properties in the second quarter of 2016 was \$16.33 per BOE, compared to \$13.19 per BOE in the first quarter of 2016, and \$28.77 per BOE in the second quarter of 2015.

Funds from (used in) operations for the three months ended June 30, 2016 were \$(0.1) million compared to \$(1.2) million and \$1.5 million in the first quarter of 2016 and second quarter of 2015 respectively. At low commodity prices, interest on convertible debentures had a significant impact on funds from (used in) operations. The Series A Debentures were settled in the first quarter of 2016 and the Series B Debentures were settled in the second quarter of 2016. There was no cash interest paid on either series of debentures in 2016. Funds from operations in 2016 include interest on convertible debentures until their maturity or redemption and all of this remaining interest was paid in common shares. Funds from (used in) operations before interest on convertible debentures were \$0.3 million for the three months ended June 30, 2016, \$(0.1) million for the first quarter of 2016 and \$3.2 million for the second quarter of 2015.

The Company reported a loss of \$4.8 million in the second quarter of 2016 due to low commodity prices and \$2.0 million in additional non-cash accretion and conversion expenses associated with the Series B debenture settlement.

The Company renewed its bank facility at \$18 million in the second quarter of 2016. The available lending limit of the facility is based on the bank's interpretation of the Company's reserves and future commodity prices. The new facility is lower than the previous \$31 million, reflecting the dramatically lower commodity prices and Company reserves in the current economic environment compared to May 2015 when the previous limit was established. The Company has not drawn on the facility. The terms of the facility include a semi-annual borrowing base redetermination on or before May 31 and November 30 of each year. The term date and maturity date were extended to May 31, 2017 and May 31, 2018, respectively.

OIL AND GAS NETBACKS

	<i>Average natural gas price (\$/Mcf)</i>	<i>Average oil and condensate price (\$/bbl)</i>	<i>Revenue (\$/BOE)</i>	<i>Operating netback (\$/BOE)</i>
Q3 2015	2.73	54.56	30.18	18.92
Q4 2015	2.40	49.78	26.53	15.16
Q1 2016	1.81	39.12	20.15	7.40
Q2 2016	1.24	52.01	22.20	8.27

Capital expenditures, before proceeds from dispositions of properties were \$0.6 million for the three months ended June 30, 2016, compared to \$1.6 million and \$(0.2) million in the first quarter of 2016 and second quarter of 2015 respectively. Capital investments in the last two quarters of 2015 and the first two quarters of 2016 were focused on maintenance activities and operating expense reduction initiatives, as well as land acquisitions net of dispositions, of \$1.0 million in the first quarter of 2016.

COMMODITY HEDGING CONTRACTS

The Company has not hedged any crude oil or natural gas volumes at this time.

The Company continues to evaluate the merits of commodity hedging as part of a price management strategy and to provide a floor for funds from (used in) operations.

CONVERTIBLE DEBENTURES

On January 31, 2016, the Company exercised its right to repay both the entire principal amount of the Series A Debentures (\$50 million) and the final interest payment (\$1.875 million) in common shares of the Company. The Company issued approximately 9.171 billion common shares from treasury at an exchange price of \$0.00565616 per common share. The exchange price was based on 95% of the 20 day volume weighted average trading price of the common shares on the TSX ending five days prior to the maturity date.

On April 1, 2016, the holders of the Series B Debentures (the "Series B Debentureholders") passed an extraordinary resolution to exchange the entire principal amount (\$46 million) of the Series B Debentures, and the interest that would otherwise accrue on the Series B Debentures to June 30, 2016 (\$1.667 million) for common shares of the Company using an exchange price of \$0.00565616 per common share (the "Exchange Transaction"). The Exchange Transaction closed and 8.428 billion common shares were issued from treasury on May 10, 2016.

SHARE CONSOLIDATION

As a result of the conversion of convertible debentures and issuance of common shares, Anderson had 17.772 billion common shares outstanding at May 10, 2016. The shareholders of the Company approved a special resolution for a share consolidation on the basis of one (1) post-consolidation common share for every one thousand (1,000) pre-consolidation common shares at the annual and special meeting of shareholders held on June 14, 2016. Articles of amendment were filed and the effective date of the share consolidation was June 15, 2016. Common shares started trading post-consolidation under the symbol "AND" on the TSX on June 20, 2016. Post-consolidation, the Company has 17,771,472 common shares outstanding. The number of outstanding common shares and the per share data have been adjusted retrospectively for all periods shown to reflect the share consolidation.

SUMMARY

The Company has made significant progress in reducing its operating and administrative costs. It has also been successful in reducing its decommissioning liabilities, both through property dispositions and an active ongoing well abandonment program. As of August 2016, the Company's Liability Management Ratio ("LMR") rating is 2.25, which allows the Company greater operating flexibility. With the downturn in oil prices, the Company has not drilled a well since January 2015 and has restricted its capital expenditures to maintenance activities. The Company has settled its convertible debentures, including the final interest payments, through the issuance of common shares. The Company consolidated its common shares on the basis of one (1) post-consolidation common share for every one thousand (1,000) pre-consolidation common shares and the new consolidated common shares commenced trading on the TSX under the ticker symbol "AND" on June 20, 2016. All of these initiatives have left the Company with no bank debt, \$5.1 million in positive working capital and no long-term debt interest payments, allowing the Company the opportunity to hunker down and wait for better commodity prices. As stated in previous press releases, the Company is planning to revisit its Cardium drilling program when WTI oil prices return to the \$50 US per bbl level. The initial return to drilling would be financed from existing cash and available cash flow. The Company does have \$18 million in unused credit lines, but given the current fragile credit markets, a mid-year bank line review in November 2016 and an uncertain commodity price outlook, using debt to finance drilling programs would be risky at this time.

Looking to 2017, the Company does have an opportunity to commence operations on its new Duvernay horizontal oil development play. Two Duvernay wells, offsetting Company lands, have been licensed to drill by other operators. Results from that drilling and continued monitoring of existing offset Duvernay production will have a bearing on the Company's Duvernay development plan.

Although the Company could restart its Cardium drilling program with \$50 WTI US per bbl oil pricing, the Company would likely require new equity to finance a return to significantly growing the Company's production. At this time, equity markets are not readily available to publicly-traded companies of Anderson's size. When commodity prices strengthen and a new drilling program is kicked off, the Company will work towards re-establishing institutional research coverage and investment dealer support. The Company does have a significant Cardium drilling inventory, an excellent Cardium initial productivity, a low capital cost historical record, and an emerging Duvernay play, which could attract institutional investor interest in a better commodity price and a better market environment.

I thank the management team, the employees and the Board of Directors for working through this difficult period. The support of our shareholders is also appreciated as we hunker down and wait for better times.

Anderson's most recent investor presentation will be posted on the Company's website at www.andersonenergy.ca.

Brian H. Dau
President & Chief Executive Officer
August 11, 2016

FORWARD-LOOKING STATEMENTS

Certain statements in this news release including, without limitation, management's business strategy and assessment of future plans and operations; benefits and valuation of the development prospects described herein; number of potential drilling opportunities; drilling program success; timing and location of drilling and tie-in of wells and the costs thereof; timing of shut-in and abandonment of wells and impact thereof; productive capacity of the wells; expected production rates and risks to such expectations; percentage of production from oil, condensate and natural gas liquids; dates of commencement of production; amount of capital expenditures and the timing and method of financing thereof; value of undeveloped land; reserves and net present value of future net revenue from reserves; ability to attain cost savings and amount thereof; tax horizon; expectations related to future operating netbacks; impact of changes in commodity prices on operating results; programs to optimize, rationalize, consolidate and improve profitability of assets, including the impact from shutting-in or abandonment of wells; factors on which the continued development of the Company's oil and gas assets are dependent; benefits of recently completed transactions including the Exchange Transaction and the share consolidation and the impact of these transactions on Anderson and its capital structure, financial position, liquidity and net asset value; growth potential of Anderson's asset base; the requirement to obtain equity financing to grow the Company's production; the ability to re-establish institutional research coverage and investment dealer support and the benefits of such coverage and support; the potential outcome of litigation and disputes; commodity price outlook; and general economic outlook may constitute "forward-looking information" within the meaning of applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation; loss of markets; volatility of commodity prices; currency fluctuations; imprecision of reserves estimates; environmental risks; competition from other producers; inability to retain drilling rigs and other services; adequate weather to conduct operations; sufficiency of budgeted capital, operating and other costs to carry out planned activities; wells not performing as expected; incorrect assessment of the value of acquisitions

and farm-ins; failure to realize the anticipated benefits of acquisitions and farm-ins; delays resulting from or inability to obtain required regulatory approvals; changes to government regulation; availability of third-party transportation and processing facilities; ability to access sufficient capital from internal and external sources; and other factors, many of which are beyond the Company's control. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as the factors are interdependent, and management's future course of action would depend on its assessment of all information at the time. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements and readers should not place undue reliance on the assumptions and forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Anderson's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at Anderson's website (www.andersonenergy.ca).

The forward-looking statements contained in this news release are made as at the date of this news release and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. Although the intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants, BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In recent years, the value ratio based on the price of crude oil as compared to natural gas has been significantly higher than the energy equivalency of 6:1, and utilizing a conversion of natural gas volumes on a 6:1 basis may be misleading as an indication of value.

Short-term production rates can be influenced by flush production effects from fracture stimulations in horizontal wellbores and may not be indicative of longer-term production performance or reserves. Individual well performance may vary.

ABBREVIATIONS

bbl – barrel
bpd – barrels per day
BOE – barrels of oil equivalent
BOED – barrels of oil equivalent per day
m3 – cubic meters
Mbbbls – thousand barrels
MBOE – thousand barrels of oil equivalent
Mstb – thousand stock tank barrels
NGL – natural gas liquids, excluding condensate
WTI – West Texas Intermediate

AECO – intra-Alberta Nova inventory transfer price
Bcf – billion cubic feet
Btu – British thermal unit
GJ – gigajoule
Mcf – thousand cubic feet
Mcfd – thousand cubic feet per day
MMBtu – million British thermal units
MMcf – million cubic feet
scf – standard cubic foot
US – United States